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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	Rulemaking 14-08-013 (Filed August 14, 2014)

COMMENTS OF NRG ENERGY, INC.

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NRG Energy, Inc. ("NRG") welcomes the California Public Utilities Commission's ("CPUC" or "Commission") new *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resource Plans Pursuant to Public Utilities Code Section 769* ("OIR"). NRG largely supports the fundamental principles set forth in the "More Than Smart" paper attached to the OIR.[1] The four key principles outlined in the Executive Summary[2] lay the foundation for a distribution grid that will provide a platform for innovation and reliability, both key objectives for California as the electric grid shifts from a centralized to node-friendly network.

NRG's expectation is that Distributed Energy Resources ("DERs") will become an increasingly prominent part of America's electric supply. Third-parties are now developing and deploying new technologies that will give end-use consumers an unprecedented level of control over their energy consumption decisions. The ability to aggregate customers at scale is critical to making DERs economically viable. A competitive framework that provides aggregators a clear and transparent price signals will drive innovative approaches to align price signals and

[1] More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient, Paul DeMartini, Resnick Institute ("More Than Smart")

[2] More Than Smart, pp. 3-4

consumer behavior with California's twin goals of decreasing the environmental footprint of the power generation sector and decreasing total ratepayer costs. As a company that is investing and innovating aggressively in distributed resources and distributed energy management capabilities, NRG is encouraged that the Commission is attempting to develop a long-term market platform that will allow such innovative behind-the-meter technologies to thrive.

As renewable and energy storage continue on the path of becoming more efficient and cost-effective, consumers will become increasingly reliant on their own energy production, storage and management, and customers will buy decreasing amounts from traditional sources. Innovation will increasingly allow smart policies to allow individuals to connect with smart, competitive energy solutions while allowing them to live truly sustainable lifestyles. One important implication of these trends is that, increasingly, private capital will increasingly substitute for ratepayer-funded capital in ways that enhance the value of the grid, while solving for the lowest cost to the consumer with the greatest reliability and the least environmental impacts.

The Commission has an immediate opportunity to take short- and medium-term actions that will boost the participation of competitive DERs in California. This includes incenting the rollout of new and expanded DER systems that rely on existing, proven technologies, as well as those that showcase cutting-edge, next-generation DER technologies.

1) *What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?*

Each Investor-Owned Utility's ("IOU's") Distributed Resource Plan ("DRP") should be required to address four main criteria: (1) facilitating DER deployment by creating a distribution network capable of managing DER interconnection and output; (2) facilitating DER operations by creating a scalable market system that supports efficient DER operation without regard to ownership; (3) bringing additional transparency to the distribution system; and (4) ensuring that private capital is deployed to further DER growth. We address each point in turn.

a. Scalable Implementation of DER Interconnection and Output.

The utilities have a critical role to play in developing the technical infrastructure on which third-parties and end-users can build tomorrow's system of DERs, which are likely to include technologies that facilitate distributed energy storage, coordinated demand reduction, electric vehicle charging, microgrids and other similar technologies. Each utility DRP should focus on what technologies are necessary to build a scalable and robust electrical infrastructure that will enable the speedy interconnection of new DERs and support the unbundled products and services of those DERs.

b. Independent and Non-Discriminatory Market Framework.

A core principle of the OIR should be that the ownership and control of distribution infrastructure should be competitively neutral, *i.e.*, independently administrated in a manner that does not prejudice or favor any particular owner or operator of DERs. As the owners and operators of the distribution network, each utility has ample opportunity to favor its own or affiliated DER deployments. Each utility DRP should thus focus on things that competitive firms are unable to do, such as deploy and maintain large scale distribution networks.

At a minimum, the Commission should ensure that each utility DRP details the functional separation measures necessary to ensure that the utilities' Distribution System Operator ("DSO") function does not create an economic disadvantage for independently owned and operated DERs.

c. Transparency in Engineering and Market Outcomes.

A third specific criterion that the Commission should require in IOU DRPs is how the utility intends to increase distribution system transparency. As discussed below, transparency in interconnection requirements, operational requirements, locational value, pricing outcomes, and dispatch decisions are absolutely critical to providing private parties the certainty necessary to invest in California, secure in the knowledge that their investments will not be undercut by non-transparent outcomes.

d. Facilitate Deployment of Private Capital and Minimize Ratepayer Risk.

Finally, every IOU DRP should carve out a clear separation between the IOU's role as a *facilitator* of DER deployment, on the one hand, and the role of competitive entities as the actual *owners* and *operators* of DER systems, on the other. This proceeding should drive innovation, avoid cross subsidization concerns, and minimize stranded cost risk associated with ratepayer-backed investments.[3] The DRPs should establish the framework by which the IOUs facilitate the technical and market structures necessary to enhance deployment of DERs, but should also ensure that private capital is spent on the ownership and operation of actual DERs.

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

NRG recommends that the Commission grade utility DRPs on whether they show improvement in the following areas:

- **<u>Interconnection Processing Times</u>:** The Commission should tie cost recovery for distribution grid investments to a requirement that the utility meet prompt interconnection processing time benchmarks for small- to medium-sized DERs. The Commission could require that IOUs complete 90% of distribution level interconnection requests within one week for small interconnections, to perhaps a month for larger interconnections.

[3] Source: Analysis of Regulatory disincentives to Utility ownership/Facilitation of DG and Remedial Issues; Synapse Energy Economics (2011).

- **Information Access:** The Commission should also grade DRPs based on whether they increase a utility's information transparency. The Commission should insist that utilities: (1) promptly make real-time meter and other relevant system information available to third parties, and (2) allow customers and their agents improved access to historic meter data.

- **Competitive DER Market:** The Commission should insist that DRPs enhance adoption of competitive DERs.

- **Rate and net metering reform:** The Commission should develop rate design and "NEM 2.0" policies authorized under AB327 that enable competitive companies to provide preferred resource products that yield energy savings benefits to customers.

- **Increased Resiliency:** Authorize and encourage end-users to adopt behind-the-meter generation, storage and other technologies that can operate in "islanded" mode in the event of catastrophic loss of the distribution system, such as can occur as a result of grid security breaches and natural disasters. Positioning these resources at strategic points across the state can ensure continuity of emergency first-responder services and ensure that key community resources remain online. Micro-grids or nano-grids that can operate even during a widespread outage thus contribute to reliability as they can reduce the demands on the system when operating in a grid-connected mode and be deployed during outages to avoid customer interruptions.

3) *What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?*

Perhaps the Commission's greatest opportunity to create broad customer benefits is to ensure that its IOUs appropriately identify where DERs should be located on the distribution network to accomplish California's environmental and reliability goals. Today, a major problem is that most end-users and third-parties deploying DERs have little to no transparency into distribution system requirements. Successful customer engagement requires a level of access to information that is, at times, sorely lacking under the existing utility model. Logically, DERs should first be located on portions of the distribution system that need reinforcement, such as areas with overloaded distribution lines, or near end-users that would most benefit from enhanced resiliency, such as first responders, hospitals, and other community centers.

"Transparency" should manifest itself in a variety of different specific sub-goals, including:

- Increased information from the utility about where distribution investments are most needed;
- Identification of potential deferred transmission and distribution ("T&D") investment that could be achieved through the deployment of third-party DERs;
- Access to clear price signals on the areas of the system where reinforcement is most needed that are tied to the value of the deferred T&D, plus the value of other attributes; and
- Transparent and speedy access to meter information held by the incumbent utilities.

To bring transparency, DERs need to be measured based on targets identified and agreed to in advance by all parties. Utilities should be incented to identify where new investments are needed, as well as the value of that investment to the utility. Putting the competitive framework for DER investments in place is absolutely a key piece of the puzzle.

To bring about this level of transparency, NRG recommends that the Commission consider requiring each IOU to divide its service territory into a limited number of "distribution pricing zones" (with the exact number to be determined by each IOU after reviewing the electrical conditions within each zone). Each Distribution Pricing Zone would provide a transparent price signal, which includes both a reservation payment (with a stated per kilowatt of capacity rate) and an energy payment (per kilowatt-hour of actual energy provided). Ideally, each IOU DRP would identify each Distribution Pricing Zone on plain, easy to read street maps, and specify the areas in which DER adoption provides the most value to the utility.[4] This transparent suite of prices would greatly aid in customers' understanding the system and the ability of third-party suppliers to finance investment in energy infrastructure. Requiring each DRP to establish one or more distribution pricing zones embodies the transparency goals

[4] NRG recommends starting with the zonal model largely because once the utility provides that information, third-party competitive suppliers and end-use customers will be able to direct their efforts to the areas on the system where DERs have the greatest value.

identified by NRG as a top goal of the More Than Smart proceeding.

4) *What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?*

The value of DER solutions to the distribution system (which could be recognized in the values assigned in a possible Distribution Zonal Price) is the sum of the following:

- Better voltage, power quality and resiliency;
- Reduced risk of thermal and other operational overloads and outages
- Improved load factor;
- Deferred, diminished or avoided investment in distribution solutions that can be provided by DER; and
- More focused, efficient and forward-looking investments in distribution assets that are complementary to DER.

In addition to these distribution system benefits, DER also provides value to the transmission system and the grid as a whole:

- Transmission losses savings;
- Deferred transmission investment;
- Value of the capacity; and
- Value of the energy and ancillary services actually produced or capable of being produced quickly in a manner that satisfies reserve requirements.

Quantifying these values can be somewhat challenging. However, as discussed above, the Commission could greatly aid the adoption of DERs by requiring each utility to translate these factors into a series of revenue streams that would be available to potential DER developers. We recommend the Commission explore requiring IOUs to identify and publish the value of DER solutions on a locational basis. This should allow competitive suppliers to bring forward the least-cost solutions for the identified need. We recommend the Commission decide at a later date whether it wishes to include externalities in its determination of value.

5) *What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?*

Too often, utility planning metrics assume zero contribution from DERs to meeting local distribution system reliability needs. This is simply not a reasonable planning approach. Instead, the Commission should require its utilities to adopt a forward-looking analysis of DER performance and ability to contribute to a more reliable system, and plan the system accordingly. The distribution engineering analysis should – and must – recognize the contribution of these resources as they become a more important part of the system.

6) *What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?*

As discussed above, DERs have the potential to help manage or avoid many operational challenges faced by distribution systems, including maintaining voltage levels, power factor, avoid thermal overloads, and a host of others. In addition, DERs can replace, reduce the cost of, or augment the value of utility investment in distribution facilities. Thus both distribution planning and operations should be modified to identify and utilize these benefits, while DER compensation, interconnection and other commercial factors should be designed to incent DER deployment.

7) *What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?*

See previous answer.

8) *What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?*

Innovation should be expected to continue to drive DER performance and capabilities, and allow DERs to increasingly improve the efficiency of the overall electric system. For this reason, integration strategies and scenarios should be forward looking and designed to encourage continued, increasing amounts of DERs. At the same time, it is important to ensure that DERs can deliver the benefits expected in those scenarios. For this reason, NRG recommends the

Commission consider relatively short planning periods, with continual updating as DER capabilities improve and are able to further reduce reliance on, and the cost of, the utility system. This will allow utilities to focus their investments on increasing the intelligence, capital efficiency, and cost-effectiveness of its infrastructure.

9) *What types of data and level of data access should be considered as part of the DRP?*

As DERs continue to increase penetration in the California energy marketplace, transparent access to data will be critical to managing and aggregating distributed resources from across the grid to bring innovation and new energy products to the market. In order for innovation to flourish, customers need to own their own information and utilities should be required to provide customers with that information as part of their monopoly charter. California utilities need to free "real-time" customer electric meter data from a rather oppressive array of restrictions on who can access the data. This will allow companies to access the data (at a customer's request) to help customers identify what energy services (solar panels, micro-grids, small efficient generators, and the like) might make sense for them. The system in which customers do not "own" their own data is anachronistic and needs revising. Moreover, this is a market reform that the Commission can implement in this proceeding, at a relatively low cost, and that will provide a material improvement to entities attempting to engage with customers on how they use and consume energy.

Further, the Commission should evaluate IOU DRPs based on their ability to provide sufficient transparency to allow third-parties to independently invest in placing DERs at preferred locations within the distribution network.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

NRG submits that any initial pilot DER projects included in the DRP must be awarded through a Request-for-Offers process. While not ideal from a competitive standpoint, the RFO model more closely tracks competitive outcomes than allowing utilities to invest directly in DERs.

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

If competitive DER deployment is not happening, the plans should be considered to have failed, be evaluated, redesigned, and redeployed.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

NRG recommends that the Commission establish clear requirements pertaining to each IOU increasing the following: transparency as to the locational value of DERs; transparency into time-of-use value for DERS, including unbundled revenue streams for energy, capacity and ancillary services; ease of interconnection, including reasonable costs and interconnection processing times; access to real-time meter data for end-use customers and their agents; and, ultimately, the success of each IOU in attracting private capital in the DER sector.

13) Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

There is broad recognition that encouraging end-users to adopt behind-the-meter generation, storage and other technologies that can operate in "islanded" mode in the event of catastrophic loss of the distribution system will enhance overall reliability. Positioning these resources at strategic points across the state can ensure continuity of emergency first-responder services and ensure that key community resources remain online. Micro-grids or nano-grids that can operate even during a widespread outage thus contribute to reliability as they can reduce the demands on the system when operating in a grid-connected mode and be deployed during outages to avoid customer interruptions.

Utilities should be strongly incented to create a competitive framework that attracts private micro-grid capital in a manner that leads to bringing these micro-grids to fruition. By expressly including a benchmark for successful competitively-sourced micro-grids in the DRPs, the Commission can send a strong message that utilities must meet and exceed expectations for increased resiliency – even though the resiliency increase occurs through non-utility spending.

14) What specific concerns around safety should be addressed in the DRPs?

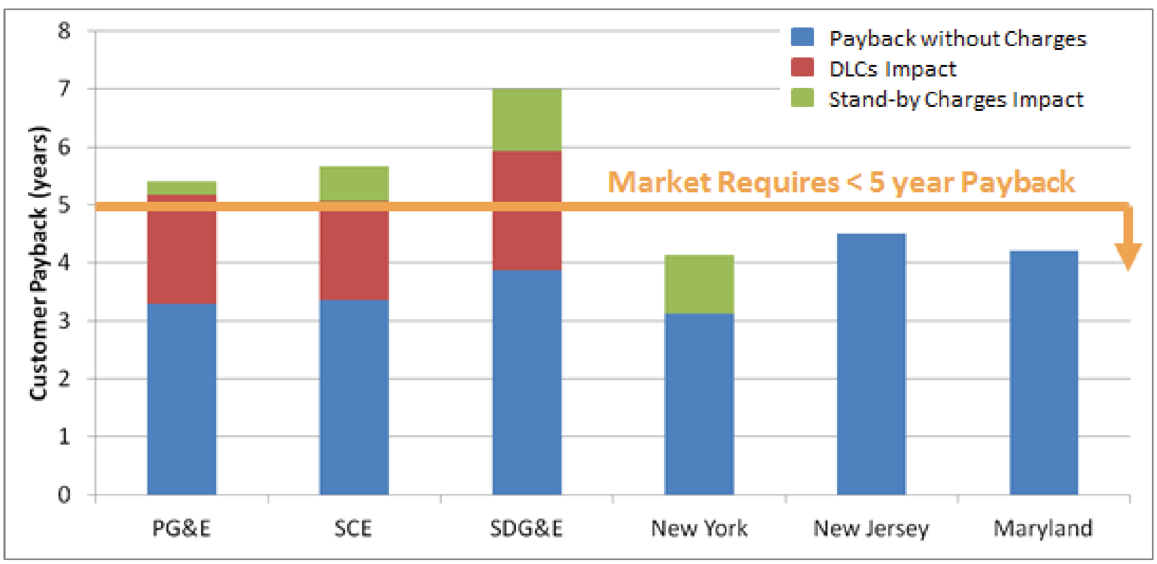
As discussed in Question 13, there is a clear value in DERs that can operate in "islanded" mode with suitable provisions to ensure isolation and safety. Thus, the DRPs should support interconnection technologies that allow simultaneous islanded operation of DERs and their safe isolation from the distribution system.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

There are several other regulatory barriers that the Commission should address as utilities continue to increasingly rely on DERs to meet system reliability needs. In particular, the Commission should require each IOU DRP detail plans to phase out, or eliminate all together, several of the regulatory barriers to increased DER penetration, including: (i) standby charges; (ii) departing load charges; and (iii) allowance of third-party DER providers to utilize existing utility infrastructure within large campuses.

First, the Commission should consider whether, as DER penetration continues, the IOUs should be required to phase out standby charges. Imposing standby charges to the totality of a DER host's total gross load creates regulatory cost hurdles that are often impossible to overcome. Standby charges only make sense where the distribution planning authority assumes no contribution from DERs across its system. As these resources become more prevalent, utilities must be required to include a statistical performance assessment in its planning processes.

Second, Non-Bypassable Charges ("NBCs")[5] for Departing Load similarly serve to make DERs more expensive, despite the obvious environmental and resilience benefits to all consumers created by the installation of DER technologies. Departing Load Charges are a particularly pernicious NBC which substantially harm the competitiveness of California's DER market, as shown in this representative project analysis:



These Departing Load Charges represent a significant cost disadvantage to DERs in California. Departing Load Charges indeed cost California ratepayers more than departing loads pay. A

[5] NBCs are a part of every ratepayer's bill (with exception of low income ratepayers via the CARE program), and are charged based on energy consumption from the grid.

recent report by Aspen Environmental Group, "*Independent Review of 'Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers'*" ("Aspen Report"), demonstrates that "from 2010 through 2013, [Distributed Generation] would have provided enough economic benefit to other ratepayers to more than offset the value of Departing Load Charges."[6] Customers interested in making a capital investment in their own energy infrastructure need to be able to disaggregate these various charges in order to truly understand whether an energy investment makes sense for them. If the Commission unbundles the various benefits charges, customers will be able to shop for competitive energy services and DER providers more easily.

Third, providers of DER services must be provided open access to distribution wires strung by IOUs within private campuses. For example, several utilities have strung "distribution" wires within California's large port complexes and separately metered individual buildings. The Commission should clarify that the IOUs must allow third-parties to provide DER and microgrid solutions using the existing infrastructure.

16) Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

- *Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?*
- *Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?*

NRG largely agrees with the Integrated Grid and Integrated Distribution Planning Frameworks proposal set forth in the More Than Smart whitepaper. In particular, the Commission rightfully identifies the need to incorporate a robust DER response into the

[6] "*Independent Review of 'Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers'*," Aspen Environmental Group (June 11, 2014), p. 3, available at: http://chpassociation.org/wp-content/uploads/2014/06/Indepenedent-Review-of-Onsite-Generation-in-CA-Potential-Ratepayer-Savings-and-Key-Barriers-Final.pdf.

Distribution Planning functions of the IOUs, including such factors as "avoided or decreased investments in distribution infrastructure, safety benefits, reliability benefits, and other savings the distribution resources provide to the electric grid[.]"[7]

From NRG's perspective, the difficulty will be in establishing an effective framework that allows end-users to derive a meaningful stream (or streams) of revenue from supplying the IOUs with the unbundled energy products that they need to reliably operate the distribution system, with additional value streams from the wholesale market. The Commission should insist that each IOU put transparent prices reflecting the value of those DER-provided services in a manner that is accessible to the average customer *and* allow DERs to interface directly with the wholesale market, as prices warrant.

- *Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?*
- *Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?*

NRG recommends that the three green boxes on Figure 4 (End-Use Customers, Merchant DER, and Micro-grid), each have the option of interacting directly with both the DSO *and* the CAISO. The highest value of some of the products associated with DERs may be in serving the CAISO wholesale marketplace. Others may have more value to the distribution system. For example, a fleet of aggregated resources may provide local distribution system thermal overload protection, power factor, VAR support, etc. That same aggregation of resources could also provide – at the same time – reserves, capacity, and VAR support, to the wholesale grid.

[7] More Than Smart, at p. 7.

Allowing DERs to seek multiple revenue streams will only aid in DER adoption rates and it is thus critical that the owner/operator of the DERs have the option to sell in both places.

- *Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?*

Integration of DER into Operations is a key piece of the DER puzzle. Entities seeking to deploy DERs must be able to monetize their investments, and do so in a straightforward manner. As discussed above, NRG supports beginning with transparent price signals for both the distribution system benefits and, as appropriate, the wholesale market benefits DERs can provide. Those prices may vary locationally or over time, but should be transparent and commercially reasonable.

Respectfully submitted,

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